

## Response to Ofgem's

### Getting more out of our electricity networks by reforming access and forward-looking charging arrangements consultation:

#### Background to ENGIE

In the UK, ENGIE employs 20,000 people in a number of activities across the energy value chain, as well as through its extensive services business.

In generation, ENGIE owns First Hydro, with a total capacity of 2088MW, this are the UK's foremost pumped storage facilities and over 70MW of renewable generation. In supply, ENGIE operates an Industrial and Commercial (I&C) and Small and Medium Enterprise (SME) B2B electricity and gas supply business, and has recently entered the domestic electricity and gas retail markets through its Home Energy business.

It owns the country's largest district heating business, providing district energy solutions to the public, commercial, industrial and residential sectors. A key site is the Olympic Park District Heating facility in London. It is also one of the top five service companies in the UK, subsequent to the acquisitions of Balfour Beatty Workplace, Lend Lease FM and the Keepmoat regeneration business.

#### ENGIE's views on the consultation - questions

**Question 1: Do you agree with the case for change as set out in chapter 2? Please give reasons for your response, and include evidence to support this where possible.**

Yes, we agree that there are significant issues associated with the current charging arrangements at distribution and to a lesser extent transmission that are driving much of the developments at distribution level.

At a domestic level charges levied on a MWh basis take little account of co-incidence of use such that distinguishing between different types of used (heat pump, night storage, solar, electric vehicle or simple domestic) is difficult. Electric vehicles and heat pumps if not "managed" correctly will require significant upgrades to the distribution system that could be avoided with appropriate charging incentives. In principle all uses have "right" to take as much power as they required within the fuse size. Solutions such as mandating half hourly meters for all none-standard uses will need to be developed along with appropriate charges as part of this review. We believe that mandating hh meters for none-standard load shapes is the "least bad option" and is preferable to asking customers to select from a menu of a connection type provided by their supplier with the associated rights and obligations depending on their selection.

At distribution the flat rate GDUoS by GSP group that was designed to provide a signal to generation to help reduce the size of the distribution system it is now in some circumstances leading to an increase in distribution cost. GDUoS provides a significant incentive to connect new generation to the distribution system and this compounds an existing distribution capacity problem and is in part responsible for the significant volume of generation awaiting distribution connections.

We agree that at a domestic level connection are “non-negotiable” this also applies to many other types of connections. For existing users we prefer cost reflective charges (as opposed to constraining use) as a basic methodology to tackle the issue identified in this consultation.

We believe that case for change has been made but do have concerns that the proposed approach will result in significant delays rather than relying on industry/ ESO lead processes. Whilst we understand the complexity of the issue the Ofgem lead process is by its nature consultative and “slow” and has the potential to delay consumer benefits by many years.

**Question 2: Do you agree with our proposal that access rights should be reviewed, with the aim to improve their definition and choice? Please provide reasons for your response and, where possible, evidence to support your views.**

Yes, we believe that the classification of access rights needs to be defined at a distribution level with a clear capacity and time of day load factor. We believe that users capacity as well as its load shape/ load factor relative to other users need to be factored into any forward looking changing arrangements.

**Question 3: Specifically, do you have views on whether options should be developed in the following areas as part of a review? Please give reasons for your response, and where possible, please provide evidence to support your views:**

Whilst the review is welcome we do believe that in some areas there will be merit in using the “sandbox” approach to trial potential solution as many of the issue to be dealt with require customer “sign on” to ensure success. This could involve “focus groups” or Ofgem working directly with specific customer/industry bodies to trial target solutions.

- a) Establishing a clear access limit for small users, with greater choice of options (as considered under b) and c) below) above a core threshold – do you agree with our proposal in paragraphs 3.5-3.10 that this should be considered? Do you have views on how a core threshold could be set?**

Whilst we broadly agree that different users should face different charges when they impose different costs on the system we do not support this being by customer “supply type choice” at a small user (domestic) level as the cost of implementing this along with the complexity at a supplier level would be prohibitive. We believe the actual load shape used relative to other users in the group should set the

charges. This alternate method based on mandating half hourly meters for all consumers with identifiable equipment that will give rise to a non-standard load profile (e.g FIT based, solar and wind, heat pumps, electric vehicles or night storage) and then the users charges are based on the specific load profile relative to the average load profile. Users that help the load profile (e.g. overnight demand) will be subject to lower charges whereas users that increase peak capacity will be subject to increased charges. These arrangements could be set at a GSP or GSP group level to reflect the realities of the specific location. Whilst this methodology initially sounds “complex” the BSC current run load profile-based software at an aggregated level and this would, concentrate the complexity with the BSC rather than at a customer level with customer choice and monitoring being required. The charge would be levied on the supplier who could then choose to pass these costs to the customers or provide incentive to customers to adjust their load profiles to minimise the supplier cost.

**b) Firm/non-firm and time-profiled access – do you agree with our proposal outlined in paragraphs 3.15-3.21 that these options should be developed?**

We believe that this is a key deliverable of this review and the interaction with GDUoS needs to be included in the definition of the problem. The significant growth of embedded generation that has led to the current level of non-firm connections has been driven in part by Triad, and GDUoS credits. Simple solution such reviewing GDUoS credits associated with non-firm connection will we believe to a large extent solve this problem without the needs for complex clarification of the basis of firm/non-firm arrangements.

At the distribution level there is not the equivalent of the SQSS and effectively the distribution companies have “oversold” capacity. We believe that addressing the commercial arrangements at a GSP level will give a better outcome than re-defining the level of curtailment rights.

We do not support users committing to temporal access rights as users need to have access when they require it and this cannot be organised in a planned way months or years ahead of real time given the nature of solar and wind forecasts.

The SQSS designs and builds a system to allow demand to be met based on diversity and we believe that this diversity needs to be built into the design of the distribution and transmission system.

**c) Duration and depth of access, discussed in paragraph 3.25-3.32 - would these options be feasible and beneficial?**

Enduring or ever green access is the only product that is financially viable. Users are unlikely to be able to attract finance for developments (generation or demand) that have uncertain future access to the system. Similarly, whilst shorter term access products are possible the lack of certainty of their availability means that these are of limited use both at transmission and distribution.

**d) At transmission or distribution in particular, or are both equally important – as discussed in this chapter?**

Our view is that the issues are similar at distribution and transmission in that enduring or ever green access is the only product that is financially viable. Generation has no value without access. Users are

unlikely to be able to attract finance for developments (generation or demand) that have uncertain future access to the system. Similarly, whilst shorter term access products are possible the lack of certainty of their availability means that these are of limited use both at transmission and distribution.

**Question 4: Do you agree with the key links between access and charging we have identified in table 1? Why or why not? Do you think there are other key links we have not identified? Where possible, please provide evidence to support your views.**

We do not believe that there is merit in defining access in terms of firmness, timed access or duration. These issues are all taken account of in the design of the system that is done with the knowledge of the type of users that are connected. Solar and wind in principle only require access during times when the renewable resource is available, the design of the energy market should drive higher prices during periods when these resources are scarce this allows thermal and storage capacity to share the connections setting a time periods for access for renewable or thermal resources given these interactions is challenging at best. We believe the key change required is to allow all generation types to respond to power price signals such that the use of the power system is driven by demand and the availability of renewable resources. At a distribution level the charges that a user faces should take account of the actual use of the system relative to other users but attempting to force users to commit to these parameters will produce a suboptimal result for customers and network costs.

**Question 5: Do you agree with our proposal that targeted areas of allocation of access should be reviewed? Please give any specific views on the areas below, together with reasons for your response. Where possible, please provide evidence to support your views:**

- a) Improved queue management as the priority area for improving initial allocation of access, as outlined in paragraphs 3.41-3.44?

For existing connection queues targeted auctions, we believe would have the results of significantly reducing the queue size as it would replace the relatively cheap cost of maintaining a position in a queue with a firm commitment to build with the resulting need to get to financial close ahead of the auction.

- b) Not to consider the potential role of auctions for initial allocation of access as part of a review at this time, as discussed in paragraph 3.44?

Yes, we support this conclusion

- c) To review the areas outlined in paragraphs 3.45-3.48 to support re-allocation of access?

We have significant reservation with a “use it or lose it approach” some generation provide “reserve” services such that they are called on occasionally, at a transmission level this is taken account in the design of the transmission system where the level of generation cannot exceed to peak demand with around 75GW of generation and a demand level less than 50 GW a significant number of connection would be potentially subject to curtailment. The use it or lose it approach suggests a fundamental misunderstanding of the nature of the power generating system.

There may be some merit in considering this approach for “dormant connection” those that have not been used for a number of years although we would expect the relevant DNO/ESO to already be taking account of this situation in the design of the system.

Question 6: Do you agree that a comprehensive review of forward-looking DUoS charging methodologies, as outlined in paragraphs 4.3-4.7, should be undertaken? Please provide reasons for your response and, where possible, evidence to support your position.

Yes, we believe that is the key deliverable of the SCR see answer to Q3b

Question 7: Do you agree that the distribution connection charging boundary should be reviewed, but not the transmission connection boundary? Please provide reasons for your response and, where possible, evidence to support your position.

We believe that the “non-firm” connection approach compared with the firm and pay for re-enforcement should be looked at in terms of the “compensation” available when access is not available as well as the benefits to the consumer of moving to a “shallower” system.

At a transmission level generator connect at typical 400kV and must fund a full “distribution system” to move from generation voltage typically 16 kV to 400 KV that involves designing and installing transformer and switchgear to gain access to the transmission. At the distribution level this is funded for and provided by the distribution company and is shared with demand.

We believe that where there are additional costs to consumers as a result of the connection of distributed generation these should fall to the generator and should not fall on consumers. The current methodology implements this but the difference between firm and non-firm connection and the rights enjoyed by both groups should be subject to further work.

Question 8: Do you agree that the basis of forward-looking TNUoS charging should be reviewed in targeted areas? If you have views on whether we should review the following specific areas please also provide these:

- a) Do you agree that forward-looking TNUoS charges for small distributed generation (DG) should be reviewed, as outlined in paragraphs 4.19-4.23?

Yes, we think that the interactions between a GSP and the transmission system need to be reviewed. Many GSP now show significant export capability and an appropriate product (similar to TEC) needs to be developed and appropriate charging arrangements put in place. How these charges are reflected on generation across and individual GSP and identifying the mapping from meter: -MPAN to GSP (as

opposed to GSP group) will be an important part of this process and potentially will benefit from an initial BSC modification or issues group discussion.

- b) Do you consider that forward-looking TNUoS charges for demand should be reviewed, as outlined in paragraphs 4.24-4.27? Please provide reasons for your response and, where possible, evidence to support your position.

Whilst we believe that there is merit in charging the residual demand change on a capacity or £/meter approach we believe that the current mechanism of charging the forward-looking charge via a “peak capacity use” capacity measure provides an appropriate signal. There is some concern that the “peak capacity use” measure the current triad approach may need to be modified to include a larger number of periods/expanding the time periods to all the winter months but in principle we do not believe a capacity measure is appropriate.

Care will need to be taken with any change to ensure that storage is not charged twice for the same connection (as both generation and demand) and the implication of any change to a capacity-based approach will need to take account of time of use and co-incidence of use by users.

Question 9: Do you agree that a broader review of forward-looking TNUoS charges, or the socialisation of Connect and Manage costs through BSUoS at this time, should not be prioritised for review? Please provide reasons for your response and, where possible, evidence to support your position.

We believe that the constraint element of BSUoS may be best placed to be recovered through increasing the cost basis for TNUoS in parallel with addressing the peak and year round element in the load flow model. The TO’s invest decision should ensure that the cost of BSUoS does not exceed to LRM cost of transmission but there is also some merit in having BSUoS constraints at a non-zero level to the customer.

The current methodology of simply applying the constraint element of BSUoS to demand and generation on the system in the half hour when the constraint occurs simply does not work and especially for storage leads to reduced demand levels that exacerbate the constraint.

Similarly apply zonal constraint cost to users that are behind the constraint driven by a forced outage on the transmission system provides no useful signal. We believe that the TO should be subject to element of the fault outage constraint cost directly as part of RIIO as this we believe will provide a sufficient incentive for the TO to maintain and invest in the transmission system.

Question 10: Do you agree that there would be value in further work in assessing options to make BSUoS more cost-reflective, and if so, that an ESO-led industry taskforce would be the best way to take this forward?

Splitting out the constraint element from the other would provide some benefit but we believe the interaction with TO investment needs to be considered carefully. It seems inappropriate that where the

TO invests heavily (new nuclear connections) there will be no BSUoS cost but when the TO does not invest heavily and relies on diversity (wind and solar) as part of the SQSS assessment users behind a lightly invested boundary should face significant short run charges compared to users behind a heavily invested boundary who face no short run cost. This is the key reasoning behind including BSUoS constraint cost within the TNUoS collection arrangements.

We do not support an ESO lead review of BSUoS. The ESO has not been active in policy areas relating to BSUoS for a number of years and in general takes a “neutral” view in areas where there are diverse views across the industry. The ESO already has conflicting obligation with license conditions (C16 ) and a financial incentive scheme that can result in the ESO supporting “sub-optimal” solutions from the customers perspective. An ESO review would simply delay change and it is unclear if the ESO will be able to manage the conflicting viewpoints it will be presented with in a better way than can be achieved via the Code modification process.

The review should be industry led via the CUSC process this is where the skills and expertise are available, this will enable debate and evidence to take place in a transparent manner with the results being presented to the Authority for decision. The recent CMP264/5 (Triad) modifications went through the industry process and is a good example of this process working well allowing all parties to present arguments and evidence to support a change. If CUSC proposal comes forward, we would expect the ESO to be part of this group supporting and providing evidence as appropriate.

**Question 11: What are your views on whether Ofgem or the industry should lead the review of different areas? Please specify which of SCR scope options A-C you favour or describe your alternative proposal if applicable. Please give reasons for your view.**

We believe that the scope of the should be the smallest possible to resolve the highlighted issue broadening the scope will simply delay a solution being for this issue. We there for support the smallest possible scope indicated by the “narrow approach” A. We also consider that where appropriate policy choices should be trialled with customer group as part of the SCR process.

We are concerned that the time scales to reach a conclusion may be protracted compared to the industry led process.

**Question 12: Do you agree with our proposal to launch an ‘Option 1’ SCR for areas of review that we lead on? Please give reasons for your view.**

Yes, we do although we are concerned that the time scales to reach a conclusion may be protracted compared to the industry process.

**Question 13: Do you agree with the introduction of a licence condition on the basis described in paragraphs 5.11 and 5.12 and Appendix 5? Why or why not? Do you have any comments on the key elements set out in table 7 of Appendix 5a, or consider there are any other key elements which should be included? Please give reasons for your view.**

We believe there are existing license conditions on the ESO to keep the charging methodologist under review and these should be sufficient

Question 14: Do you have any comments on the draft wording of the outline licence condition included at Appendix 5b? Please give reasons for your view.

No

Question 15: What are your views on our indicative timelines? Do you foresee any potential challenges to, or implications of, the proposed timelines and how could these be mitigated?

We believe that industry should play a part in developing solution via modifications that have recently been discourage Ofgem potentially raising an SCR in this area, we think that it is unfortunate the Ofgem “discouraged” the continuation of the CMP 271/4 modification groups that with appropriate chair would have delivered helpful conclusions in some of these work areas.

Question 16: What are your views on our proposals for coordinating and engaging stakeholders in this work?

We believe that the BSC and the CUSC process should be the main vehicle for industry lead change and stake holder engagement.

For further information, please contact:

Simon Lord  
Transmission services Director  
ENGIE UK

Tel: 07980-793692  
Simon.lord@engie.com